ELECTRICITY PRICING IN THEORY AND PRACTICE

S.Ramesh

Discussion Paper No.08.84
Tata Energy Research Institute
New Delhi

CONTENTS

1. PUBLIC UTILITIES AND PRICING

Public utilities such as electricity systems, transport networks, etc. provide basic services essential to daily life, and as such, the State has a vital stake in their pricing and distribution. They are also "natural monopolies", in so far as the nature of the service provided by them is such that, over considerable geographical areas, they can function properly only under conditions of monopoly. This is because large "indivisibilities" (also called "lumpiness" by several writers) characterise investments in these industries. For example, if there are two electricity supply systems operating within the same geographical area, the resulting over-investment and waste owing to criss-crossing of distribution lines can readily be imagined. The nature and characteristics of public utilities have, therefore, inevitable implications for pricing from the fiscal and welfare view-points, which are often in conflict with one another.

2. NATURE AND CHARACTERISTICS OF ELECTRIC UTILITIES

Apart from being a natural monopoly, the electricity supply industry has specific economic characteristics of its own, both on the supply and demand sides, which have implications for pricing in electricity undertakings. On the supply side, there are different types of capacity producing electricity and they work as part of an integrated system. The costs of supply vary by voltage and by time of supply. There are also uncertainties on the supply side, such as variable generation in hydro plants depending upon water inflows, and unpredictable break-downs (known as 'forced outages' in the industry) mainly of thermal power plants. Apart from this uncertainty of supply, a major economic characteristic of electricity is its non-storability.

On the demand side also, there are some important features which must be noted. The demand is variable by time of day, season, etc. and this variability, combined with the non-storability on the supply side, has major economic implications which we shall be examining presently.

This monopolistic nature of electric utilities enables them to practise price discrimination in suitable cases. The conditions necessary to practise differential pricing are: (1) Monopoly/near monopoly on the supply side; (2) A total demand that can be further sub-divided into separate markets, each with a different price elasticity of demand;* and (3) Some means of insulation of each market from the others, so that those who buy at the lower price cannot resell to those who would have to pay higher prices.** It is clear that all these conditions are fulfilled in electric utilities which can, therefore, practise differential pricing. Differential pricing enables the utility to balance fiscal objectives with welfare objectives, which are conflicting to a certain extent; more important, it enables the utility to adjust its prices for different consumers or consumer-groups, in order to recover the differential costs imposed on the utility by them.

3. OBJECTIVES OF SOUND PRICING SYSTEM

There are three main objectives of a sound pricing structure which can be generally stated as:

(a) A fair return and adequate revenues;

(b) A fair distribution of costs among consumers; and

(c) rates that discourage waste and promote all justified uses of utility services, and ensure efficient allocation of resources.***

The concern for "fairness" in the rate of return arises from the possibility of misuse of the monopoly power of electric undertakings. The criteria of fairness obviously would depend on several considerations, including the magnitude and behaviour of national economic variables. Fairness in distribution of costs

---

* The price elasticity of demand is defined as the ratio of the percentage change in quantity demanded to a 1% change in price, and measures the responsiveness of quantity demanded to changes in price.

** George J Stigler, page 223.

*** Bonright, James C, (1964).

among different consumers, results from the genuine concern that, as far as possible, the buyer should pay the cost of the services provided. The third objective is perhaps the most important, as it concerns efficient allocation of resources, which is particularly important in developing countries.

4. TECHNICAL PROBLEMS OF ELECTRICITY PRICING

The technical problems in this area, are those of tariff making which are: (a) complexity due to the mass of technical detail, which must be considered in designing/administering rate schedules; (b) "ignorance" of rate-makers of demand and supply functions; and (c) the need to consider numerous conflicting standards of fairness and functional efficiency.* These technical problems play a very important role in the study of electricity pricing. An electricity supply system is a complex network of different kinds of generating capacity, a transmission network to transmit electricity from the generating centres to the load centres, and a distribution network which provides supply to the ultimate points of consumption. The tariff-makers generally do not have adequate information, especially on the demand side; ideally, the elasticities of demand of different categories of consumers should be known for an efficient tariff exercise, but generally this information is not adequate, and the tariff-makers have to make use of available estimates.

5. APPROACHES TO ELECTRICITY PRICING

Pricing policies in the electricity industry, even in developed countries, have historically been dominated by professional utility managers and engineers. The traditional approach is basically an accounting approach.** This approach is based on a calculation of historical costs as derived from the accounts of the utility. Obviously this involves a comprehensive stock-taking of all assets, old and new. Using this stock-taking, certain "capacity related" costs are derived and

---

* Bonbright, (1964).

** The word "accounting" is used in electricity economics, in the sense "as based on the financial accounts".

various "energy related" costs are evaluated. Maintenance costs are allocated to the former or the latter as considered necessary. Purely "customer related" costs are allocated as equitably as possible among customers on the basis of who has imposed costs on the utility. A tariff structure is formulated for each customer class, which includes KW charges as well as KWHr charges.

The basic principles underlying the above approach, which still govern rate-making all over the world, are that accounting or historical costs, should form the basis of pricing*.

Economists are now generally agreed that the accounting approach is inadequate for efficient resource allocation. The economic argument goes as follows. Accountants are concerned with the recovery of historical or sunk costs, whereas resource allocation emphasises the actual resources saved or used by every consumer decision. According to this argument, "bygones are bygones" and historical costs have no relevance to decisions which are made today, which involve resources in the present or in the future.

Prices based on historical or accounting costs, are also inadequate as signalling devices. Prices should be 'signals' to consumers to increase or curtail their consumption and need to be related to the incremental costs of meeting that consumption. The economist's argument would be that prices should reflect these incremental (or marginal) costs and thus provide the correct signals for the consumption changes. In the words of Turvey and Anderson, "the backward looking estimate of the traditional approach, creates an illusion that resources...................... are as cheap or as expensive as in the past. On the one hand, this may cause over-investment and unnecessary scarcity. In addition, if the past holds a number of poor projects, the sunk costs of mistakes, if reflected in prices, will overstate the costs to the consumer of extra consumption, which is not efficient .... for efficient resource allocation, prices should be related to the resource costs of changes in consumption; i.e. pricing according to marginal, not average, cost. The change in the cost to a consumer of altering his electrical behaviour will then mirror the change in the cost to the enterprise".*

---

* See Turvey R. & Anderson D, (1977),Chapter 2.

In being inadequate as a signalling device, the accounting approach ignores the incentive effects of tariffs. Tariffs give incentives to consumers by telling them when electricity is cheap, e.g. during off-peak hours, and when it is expensive, e.g.during peak hours. Incentive effects are obviously relevant in regulating electricity demand in accordance with the requirements of the undertaking, which incurs different costs during different periods of the daily cycle. The average accounting costs, being unrelated to the incremental cost of supply in different periods, are thus inadequate in this respect. We shall return to this point later in this paper.

6. THE GENERAL CASE FOR MARGINAL COST PRICING IN ELECTRIC UTILITIES

Marginal cost pricing has a long history in economic literature starting with the famous article by Hotelling in 1938, which itself was an elaboration and a modification of an earlier contribution by a French engineer, Dupuit.*

In the earlier literature, considerable emphasis was given by economists to the problems of a deficit arising out of marginal cost pricing in public utilities subject to decreasing costs. This earlier literature concentrated on the "excess capacity" case, where unit costs were decreasing over the relevant range of the cost curve, as a result of indivisibilities. The various alternative means of meeting the deficit, and their welfare implications, were considered in detail in this literature.**

The emphasis of the earlier literature on the problems arising from decreasing costs, has now given way to the problems of pricing in an expanding electric utility industry.

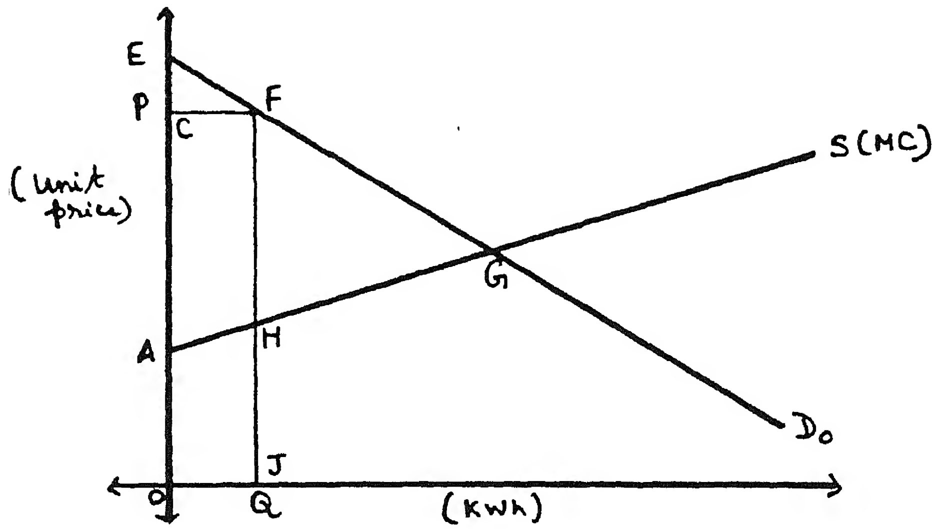
The theoretical rationale for setting prices equal to marginal cost in an electric utility has been well explained by many writers. The following diagram, adapted from Munasinghe and Warford, explains the basic marginal cost theory.***

---

* Hotelling F, (1938).

** For detailed references, see Nancy Ruggles, (1968)

*** Munasinghe and Warford, (1982).



In the above diagram, $EFGD_o$ is the demand curve (which gives the KWH demanded per year on the horizontal axis and the average price on the vertical axis), while AGS is the supply curve showing the marginal cost of supplying additional units of output. At price p and demand Q, the total benefit derived from consumption of electricity is represented by the consumers' willingness to pay, i.e., the area under the demand curve, OEFJ. The cost of supplying any quantity of electricity is given by the area under the supply curve, i.e., OAHJ. The total benefit minus total supply cost, is, therefore, the net benefit derived from the consumption of electricity, i.e. the area AEFH. The objective is to maximise the net benefit, and this is clearly achieved at the point G (price p_0, quantity Q0. In mathematical terms, the net benefit is given by:

$$NB = \int_0^Q p(q)\,dq - \int_0^Q MC(q)\,dq$$

where p(Q) and MC(Q) are equations representing the demand and supply curves respectively. Maximising NB:

$$\frac{\partial(NB)}{d(Q)} = 0, \text{ i.e. } p(Q) - MC(Q) = 0; \; p(Q) = MC(Q)$$

showing the point of intersection of the demand and marginal cost curves (price p_0, quantity demanded and supplied, Q_0).

In actual practice, of course, adequate information regarding the demand curve may not be available, though the marginal cost curve may be estimated more accurately. Therefore, the establishment of the equilibrium point, or market clearing price, will be an iterative process. However, the conceptual basis for setting price equal to the marginal cost, and increasing the supply of electricity until the market clears, remains valid.

From the point of view of society in general, it can be stated that the purpose of pricing should be to allocate national resources efficiently by providing appropriate signals to consumers. Prices act as signals to consumers who see them as costs of using the commodity, which in this case is electricity. If the price of electricity is fixed below its marginal cost of production, consumers will think (and act accordingly), that the cost of an additional unit of electricity is less than the cost to society. In this case, more resources would be devoted to electricity production than is socially efficient.*

It may be objected that, while the above logic is valid for new consumers, it does not justify charging marginal costs to existing consumers. Here it must be explained that all consumption is new in the economic sense. Just as B, a new group of consumers, may impose on the electric utility the need to add to system capacity because of their (new) additional requirements of electricity, so can an existing group A impose this need on the utility by continuing their consumption; after all, group A can save additional costs to the utility by reducing their purchases. As Kahn points out, A's continuing to take service is just as responsible, in proportion to the amount they take, for

---

* This argument presupposes the absence of "externalities", such as pollution costs, etc., and also that all costs are measured in terms of social costs. Strictly speaking, marginal costs are marginal social costs, and the marginal costs as calculated in actual practice, are only approximations to the marginal social costs.

the need to expand investment, as B's increasing needs. Even though B's demand is marginal in a temporal sense both groups are marginal in the economic sense.*

Marginal cost pricing in electricity therefore involves a tariff structure so framed that the cost to any consumer of changes in the pattern/level of his consumption, equals the costs to the electricity industry as a consequence of his action. Such pricing will cause individual consumption decisions to conform to the national interest if (a) consumers are well-informed and rational, (b) the distribution of income is taken as given, (c) the cost to the industry of responding to consumption changes coincides with social costs i.e. value to the economy of the resources involved (this means absence of external economies/dis-economies), and (d) prices of substitutes/complements for electricity, are equal to their marginal (social) costs; a similar condition exists in the case of prices of goods using electricity in production.**

Though the above conditions are not met fully in any economy, Turvey concludes that there is a presumption in favour of marginal cost pricing for the following reasons: Firstly, consumers' rationality is not an unrealistic assumption. Secondly, the electricity industry should not try to set right (by tariff policy) the distribution of income in any manner, as that is a more appropriate field for fiscal policy; in that sense, it should act as if the distribution of income is acceptable. Thirdly, as all other prices are not equal to marginal cost, and there are some external economies/diseconomies,*** the problem becomes one of 'sub-optimization' i.e. second best.

The argument used sometimes against marginal cost pricing is that the rule is really an "all-or-nothing rule", in the sense that it does not help efficient resource allocation in its application to one industry unless it is applied to all others. Here it may be

---

* See A.E. Kahn, (1970).

** See Turvey R., (1968), for a fuller discussion.

*** Examples of externalities in the electricity industry,are atmospheric pollution caused by thermal stations, and environmental problems (owing to effects on flora and fauna in the area) of hydro-electric projects.

pointed out that interdependence between various activities is not as complete as implied in the above argument. What is relevant to marginal cost pricing is the situation regarding substitutes and complementary goods.* Where a substitute is priced lower than marginal cost, obviously marginal cost pricing for electricity cannot lead to efficient resource allocation. Resources devoted to producing electricity, will be influenced by such deviations, the more so if they concern close substitutes/complementary goods. Therefore, "........... the right policy is to pursue marginal cost pricing for electricity subject to corrections made only for those non-optimalities which are known to have a significant effect on the demand or cost structure of electricity".** Even in the case of these non-optimalities, it is suggested that it may be better to tackle them directly wherever possible, than allow for them in electricity pricing.

7. SHORT-RUN AND LONG-RUN MARGINAL COSTS

The difference between short-run marginal costs and long-run marginal costs can be stated very simply. Short-run marginal costs represent the marginal costs of supply, when capacity is given. In the long run, however, we can add to the system capacity and, therefore, the costs can be different, depending upon the mix of capacity that can be made available in the longer run. Theoretically speaking, short-run and long-run marginal costs would be equal, if output is optimal. Short and long run marginal cost pricing are in fact equivalent if correct forecasting is done, i.e. if future assumptions made in calculating long-run marginal cost turn out to be valid. However, anticipations of the future demands can prove to be over-estimated or under-estimated and there can be a difference between the two marginal costs at any point of time. Boiteax has shown that, whatever the capacity of existing plant, the need to keep prices steady, makes long-term policy

---

* See M.J. Farrell, (1958), for a detailed discussion of this point. Examples of substitutes are gas in developed countries, and Kerosene oil (for lighting) and diesel oil (for engines, motors etc.) in developing countries.

** Turvey, (1968)

preferable to the instantaneous, optimal use of investment, i.e. the proper approach is fix prices equivalent to long-run marginal costs.* As short-run marginal costs can vary from time to time frequent changes would also be implied in the pricing system. In an actual situation, distortions can arise in the short run, if prices are based on long-run marginal costs. Though it is accepted that the relevant signals to consumers should be still based on long-run marginal costs, practical problems very often result in a situation where it may not be possible to follow these rules strictly. For instance, Electricite de France, who were the first electric utility in the world to systematically introduce and refine the application of marginal cost pricing, faced this problem after the 1974 oil crisis. The experience of the EDF in meeting this crisis and the resulting implications for electricity tariffs in France have been reported in a paper by J.Pl. Roux of the EDF.** When the price of oil tripled in 1974, marginal energy costs also tripled, as oil-fired stations were at the margin. Meanwhile, the new economic conditions called for a changed long-term generation mix, and, in the new optimal investment plan, the nuclear programme accelerated significantly. In the new structure, marginal energy cost was the cost of nuclear fuel. EDF thus faced a conflict between short-term and long-term marginal costs. If they had immediately adopted long-term marginal cost pricing, as dictated by economic principles accepted by them, EDF would have faced a financial crisis in the short run. The compromise adopted by EDF, was a gradual adjustment to the LRMC over a few years, progressively narrowing the gap between the price and LRMC. This example shows the difficulties of a strict application of marginal cost pricing in a period when economic conditions are changing fast.

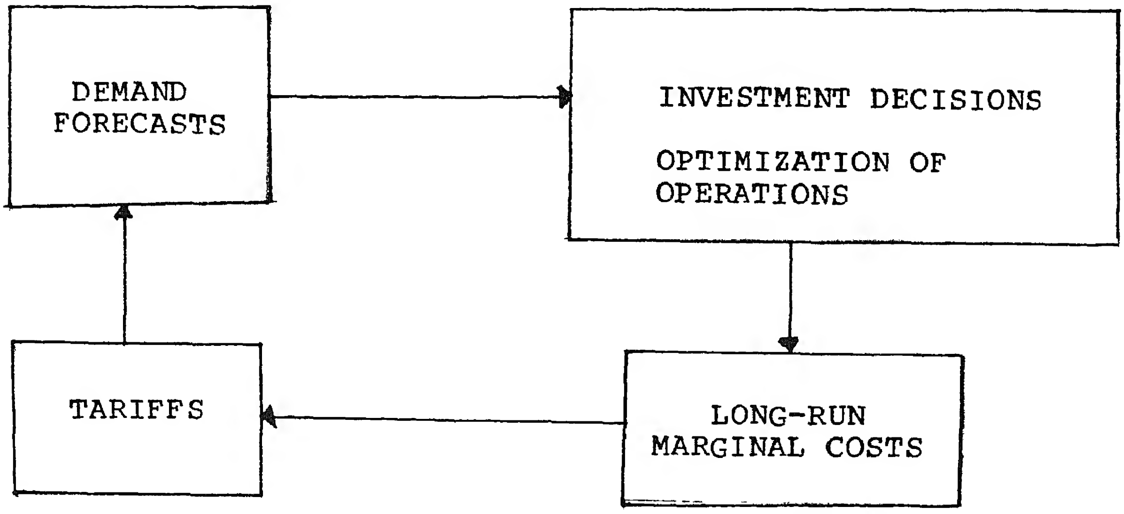
The long-run marginal cost is thus the correct basis for tariff policy, as such a tariff system would promote rate stability and also provide consumers with good long-run signals. It has been explained earlier that tariff making is a continuous iterative process. One point that must be emphasized about long-run marginal cost is that it is always related to a specified (future) load increment, and, therefore, must

---

* See Boiteax (1964a).

** Roux J.Pl., (1984).

be related to an optimal long-term investment plan. The following diagram shows how this iterative process can operate in principle.



As is clear in the above diagram, an optimal investment-cum-operation plan to meet a certain demand forecast in a future year (say 2000 AD) is prepared, and the long-run marginal costs are based on this mix. The tariffs resulting from this LRMC are again used to make revised demand forecasts which in turn result in a revised optimal investment plan which again results in a new LRMC structure and so on, until the gap is significantly narrowed. In practice, of course, a more pragmatic approach can be used where LRMC resulting from one iteration, will be the basis for new power tariffs. The demand behaviour is observed over some time period, after which the LRMC/tariffs are re-estimated.*

LRMC, therefore, is always related to a specified load increment and there can be as many LRMCs as there are load increments. To put it more rigorously, LRMC in year N of a given load increment will be equal to the excess of the present worth of the increment of system costs resulting from a permanent load increment starting at beginning of year N, over the present worth ....year (N+1). In substance, LRMC in present worth terms is simply the present worth of all system costs to meet the specified load increment, less what they would be without that increment. It must be noted here that the increment is not only of capital costs but of system costs i.e., it would include fuel savings etc., which could arise because of the change in the mix of generating capacity, with attendant implications for operations.

* Munasinghe and Rungta, (1984).

8. INGREDIENTS OF LONG-RUN MARGINAL COSTS

The ingredients of long-run marginal costs in an electricity system (in relation of course, to the specified load increment for the specified future year) are:

(a) Generation capacity costs.

(b) Transmission and Distribution Capacity Costs -- at each voltage level, including transformer costs.

(c) Energy (or running) costs and losses - at each voltage level.

(d) Customer or connection costs.

9. PRINCIPLES OF PEAK LOAD PRICING

Peak load Pricing in electricity, is a recognition of one important characteristic of electricity, namely, that demand varies according to the time of the day/ season, but the supply is non-storable. The marginal costs of supply, therefore, vary according to the time/period of supply. The change in cost of supply (at different periods of the daily cycle) with an existing capacity, and <u>additional</u> capacity cost arising from capital <u>expansion owing</u> to the characteristics of demand, must be clearly distinguished from one another. Even with the existing capacity, (which is itself a mix of plants of differing efficiencies), energy costs (i.e. variable costs) can vary during different hours. With unevenly distributed demand, plants come into operation in accordance with the rule that the most efficient plants work first, followed by successively less efficient (i.e. more unit costs of operation) plants in the 'merit order' of operations. When capacity is variable, the costs of supply when demand is pressing against available capacity, may involve additional capacity. This would imply incremental costs of capacity which would be part of the long-run marginal costs of supply. It is equally obvious that, since the capacity of the system (generating stations, transmission and distribution lines, transformers of various types etc.) is determined by the highest demand it is expected to meet (generally referred to as the 'system peak'), there is necessarily considerable spare

capacity during the hours other than the hours of peak demand. The theory of peak load pricing, explicitly recognizes these differential marginal costs, and proposes a tariff where the price is time-differentiated i.e. a type of tariff which varies over a daily (or seasonal) cycle, according to the level of kilowatt demand on the system.

Since demand for electrical energy can vary every instant, the problems of applying a time-differentiated tariff, are evident. The metering and other costs of such a variable tariff-structure, quite apart from the costs by way of public inconvenience etc., prevent such an extreme application of time-differentiated pricing. In actual practice, therefore, peak load pricing envisages the decomposition of the load curve (the curve showing the relationship between the quantity of power supplied and the period of time of supply in the daily cycle) into as many adjacent levels as will properly represent it. As a practical proposition, the number is to be kept as low as possible.*

In a simplified illustration used by Boiteaux, we consider a load curve broken into six independent levels, each level with its own demand, as shown below.

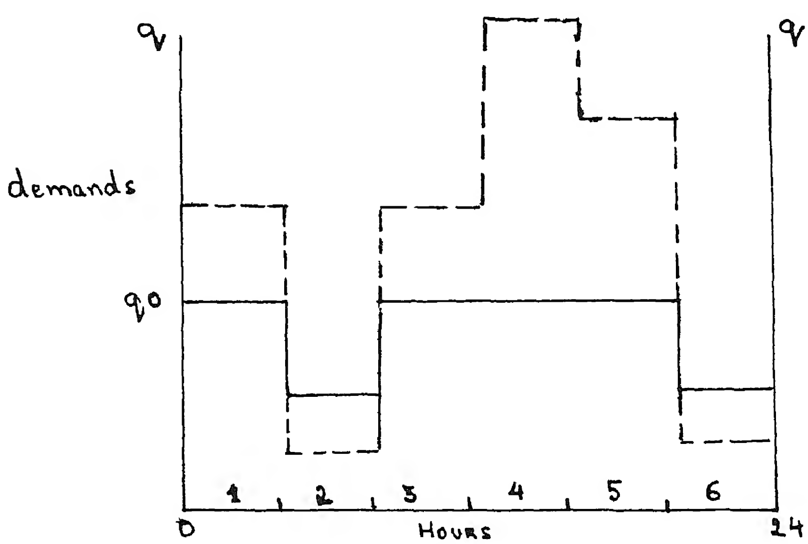


Figure ...Load Curve before and after peak-load pricing; breakdown into six levels (dotted line shows load curve for time-uniform pricing; thick continuous line shows load curve obtained after peak-load pricing)

---

* Boiteaux R., (1964b). This is the pioneering article in the field of peakload pricing. See also 'Symposium on Peak Load Pricing', (1976).

The principles of peak load pricing in the above model, are basically simple. At every level, prices will be set so that the load curve is brought to follow a horizontal line. If, however, the prices needed to bring demand to this horizontal curve were less than the energy cost* (what Boiteaux calls 'partial cost') for any off-peak levels, the tariff would not be reduced below energy cost, but the load curve will be allowed to fall below the horizontal line. In the above simple model, off peak demands 2 and 6 bear energy costs only, and demands 1, 3, 4 and 5 are brought down to the level of the horizontal line by a suitable charge for each demand to meet the cost of plant of capacity q_0. Here it must be pointed out, that the horizontality is achieved by the combined action of two forces - (a) direct pressure of the differential price in each period and (b) 'stretching' effect on the load curve, because of interchangeability of the consumption, which partly moves from more expensive periods to cheaper ones.

From the illustration above, it is clear that the time-uniform price (which results in the dotted load curve) is higher than energy cost during periods 2 and 6, and lower during the remaining periods 1, 3, 4 and 5. While the price is lowered to be equal to energy costs during periods 2 and 6, the price has to be raised above energy costs during periods 1, 3, 4 and 5 by adding to it an additional charge (separately for each period) to bring down the curve to the horizontal line as shown above.

The concept of 'investment responsibility' explains the basis of the charge during the periods 1, 3, 4 and 5. The investment responsibility of an hourly demand is equal to the proportion of the power costs which must be charged to that demand in order to bring it down to the optimum horizontal level. Seen in this light, it is clear that the theory of peak load pricing is but a part of the general theory of long-run marginal cost pricing, where the incremental capacity costs are charged to those periods according to the investment responsibility as defined above.

---

* This could be called 'variable cost' also. We use the term 'energy cost' because it expresses the significance of the concept properly, apart from being generally used in current literature relating to Electricity Economics.

It is also important to emphasise here, that the relevant peak for peak-load pricing is not the actual peak as derived from the present load curves, but the 'potential' peak. The marginal cost is also based on what the load curves become after the tariff has changed the consumers' behaviour e.g., in our simplified model, the continuous load curve will be the basis of the marginal cost, and not the dotted load curve.* The economic argument for the peak capacity charge, and the favourable treatment (by way of lower price) given to off-peak consumption is briefly that, every peak user imposes on the undertaking and the society in the long run, the incremental cost of the capacity he draws, whereas such a causal relationship does not exist between off-peak use and capacity costs. It would be thus be unfair to levy capacity costs on the off-peak user. Further, in so far as off-peak consumption has any elasticity at all, such a charge would reduce off-peak consumption, and some capacity is left idle wastefully.**

In theory, peak-load pricing can be applied to all classes of consumers. Practical considerations as well as the costs of metering, billing etc. in the case of time-differentiated pricing, have prevented full implementation of this principle even in countries such as France and Britain which have been pioneers in this field.

10. ACTUAL EXPERIENCE OF PEAK LOAD PRICING

It would be instructive to briefly mention the experience of peak load pricing in some countries. The problem really is to strike a balance between an "ideal" tariff with its attendant costs of complexity and the entirely non-time-differentiated i.e. time-uniform tariffs. France introduced in 1956 the first marginal cost based tariff in any major system in the world and applied peak load pricing only to high voltage consumers. This consisted in the introduction of five different daily rates, for each of the six voltage levels of supply. Three of these rates pertain to the (peak) winter months and two to the summer months. The

---

* See Boiteaux and Stasi, (1964).

** See also Kahn A.E., (1970).

three rates in winter were: (a) the highest rate during the three evening peak hours, (b) "full-use" hours - the next highest rate - covering day time hours, and, (c) the "slack" night hours. In the remaining (summer) months, there were two rates covering "full-use" and "slack" hours only; "full-use" being defined as all the hours other than the "slack" night hours. The winter rates were much higher than the summer rates and the price differential was approximately 4 to 1 from peak to off-peak hours.* The effects of the above tariff were evident after a year of actual experience, when the national load curve was noticed to have flattened out at the peak to the extent of approximately 5%. This meant a reduction of 300MW of peak demand and considerable saving of fuel and foreign exchange. The total economy (including investment on transmission and distribution, which also depend on peak demand) was estimated at more than 50 billion francs for the seven years following introduction of the new tariff.**

France continues to be an example of the application of marginal cost pricing and peak load pricing to electricity. The latest amendments in the French tariff structure have been reported in the paper by Roux.*** The EDF have taken into account the changes in the energy supply structure in France, where the share of oil is declining, and electricity is increasingly being produced from nuclear sources. It has also been found that the seasonality of electricity demand has increased significantly. This is because of a change in the pattern of working hours resulting in a lower growth of consumption during the summer. It is also seen that the daily load curve has flattened out considerably, but the shape of the yearly load curve has deteriorated, and is expected to do so further. Therefore, as Roux observes, there is a "transition in the electricity supply system from a peak of a few hours a day during a good many days a year, to a system whose peak corresponds to a large number of hours the same day, but only during a few days

---

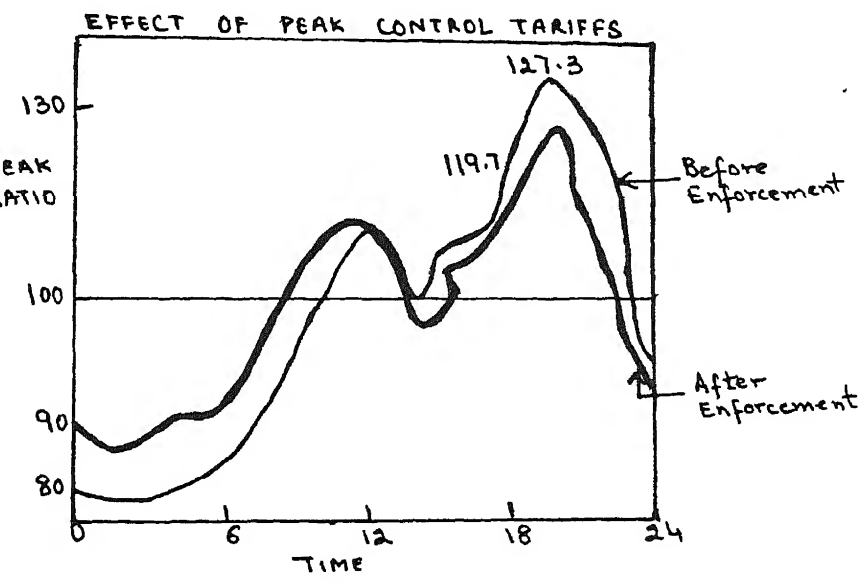
* Because of increased heating demands the requirements of power increase substantially in winter in France.

** See Pierre' Masse', (1964), and also Meek R.L., (1973).

*** J.Pl. Roux, (1984).

a year, but at dates which cannot be foreseen". The new approach to revising the French tariff takes into account these phenomena.*

Korea is one developing country which has recently tried to implement peak load pricing. Since the objective of peak load pricing is to flatten the load curve and utilise capacity more evenly, it was important for KEPCO (Korea Electric Power Corporation) not only to know the load pattern, but also to make an assessment of the likely consumer response to the peak load tariffs. In the Korean system, the peak occurred between 5 p.m. and 10 p.m. Apart from calculating marginal capacity cost, and marginal fuel cost, the organization had to make the required forecasts besides deciding on the appropriate pricing periods. In analysing possible consumer response to the proposed peak load tariffs, KEPCO conducted a survey and also utilised an independent survey by the Korean Chamber of Commerce and Industry. Using these sample surveys, they estimated that, by adopting peak load tariffs, the load curves could be flattened by at least 15%. During the 18-month preparatory period, KEPCO explained the forthcoming tariffs to prospective customers. The results of the enforcement of the peak load tariffs are shown in the following diagram.



---

* Space does not permit a detailed discussion of the new French approach. Briefly, the new tariffs will be based on demand rather than voltage. Secondly, since the nature of peak problems has changed completely, the new system proposes a "Peak Day Withdrawal Option" which is expected to enable the EDF to tackle the new peak problem effectively. For fuller details, see Roux, (1984).

As seen in the above diagram, the peak ratio (ratio of peak-load to average-load) before the peak tariffs, was 127.3, but it came down to 119.7, and the off-peak ratio at night, increased from 79.5 to 85.7. KEPCO has estimated a possible saving of US $250 million in new investment as a result of peak load pricing.*

11. MARGINAL COST PRICING AND THE REVENUE OBJECTIVE

We have explained how marginal cost pricing of electricity aids in proper resource allocation, by giving the appropriate signals for decision-making in the electric utility industry, especially in the planning of the level of capacity. But it is well known that resource-allocation is not the only objective that the policy makers place before the utility. In most countries, developed as well as developing, the utilities are faced with a revenue objective as well, usually in the form of a required rate of return on capital investment.

The objective of efficient resource allocation leads to long-run marginal cost pricing, as we have explained earlier in this paper. As far as the revenue objective (i.e. a required rate of return on capital base of the utility) is concerned, it is obvious that it is an accounting concept, and is thus based on the relationship between average accounting (i.e. historical) costs and price. It has been pointed out earlier that no a priori relationship exists between average accounting costs and marginal costs in a real-life electric utility, with its mix of different types of plants.

Marginal cost pricing may, therefore, result in a deficit, or a surplus that is smaller or greater than the predetermined target, depending upon the actual situation in the electric utility concerned. The conflict arises because average accounting costs are an average of different types and ages of plant, and marginal cost is the incremental cost of new plant at current prices. The observed difference between average accounting costs and marginal costs, can therefore, be very often substantially accounted for by inflation and the firm's accounting practices.

---

* For a discussion of the Korean experience, see Yoon Hi Woo, (1984).

In the short-run situation of excess capacity (i.e. where demand is below the available capacity when electricity is priced at marginal running cost), a financial deficit can arise with marginal cost pricing, as capacity costs are not covered by the short-run rule. However, there is no question of excess capacity in the long run, and we have already explained how capacity costs as well as energy costs are covered by the long-run pricing rule.

The problem then becomes one of reconciling the objectives of resource allocation and the required rate of financial return, the latter being regarded as overriding. Originally, many utility managers and engineers saw in this conflict, the necessity for some sort of average cost-plus pricing, which alone could ensure the achievement of the revenue objective.

From the accounting point of view, long-run marginal cost would include the opportunity cost of capital. Actually, the concept of 'surplus' is purely an accounting concept, and is clearly based on the relationship between average accounting costs and price. What we are advocating is that long-run marginal cost should be the starting point of any pricing policy, and that the revenue surplus (i.e. over and above the average accounting costs) objective, should be considered when making deviations from marginal cost-based prices. In this connection, reference must be made to the important contribution of Baumol and Bradford*. These authors demonstrated for the first time, in a systematic fashion, how, in theory, the demands of resource allocation can be reconciled with the requirements of the revenue objective. Where marginal cost-pricing yields an overall deficit, the revenue constraint would require upward revisions in marginal cost-based prices. If we assume that the revenue constraint is overriding, then the problem becomes one of 'optimal' deviations from marginal costs, i.e. such deviations as would cause the least changes in consumption of different categories, from that dictated by marginal cost-based prices. This would imply pricing according to the "inverse elasticity" rule, i.e. maximum deviations in prices of those consumer categories with the least elasticities of demand. In the case of a

---

* Baumol and Bradford, (1970).

revenue surplus arising from marginal cost pricing, the reverse procedure applies, i.e. maximum decreases in prices of those consumer categories with the least elasticities of demand.*

12. ELECTRICITY PRICING IN INDIA

In this section, we shall briefly review the current state of electricity pricing in India, with a view to suggesting some steps towards a rational pricing policy. The electric utility industry in India is largely under the control of the state electricity boards, each of which has its own set of tariffs. No attempt will be made in this section to review in detail the tariffs of any particular state utility; the objective is more to stress certain common features of their tariff structures. The observations made in this section, therefore, apply broadly to all the utilities in India, though there may be some exceptions in certain cases.**

The state utilities have their own sets of tariffs, but the level and structure of the tariffs are broadly similar. Most of them have a two-part (demand charge as well as energy charge) system for the industrial high voltage tariffs, and tariffs consisting only of energy rates for domestic, commercial and other categories of small consumers. All of them have separate tariffs for agricultural pumpsets/tubewells, the growth of which has been an important feature of the development process during the last 15 years.

An important feature of most of the utilities is that they are incurring financial losses, despite the statutory obligation under the Electricity Supply Act, which imposes on them an obligation not to incur losses in their operations. The revenue losses per year exceed

---

* This is the theoretical position. In practice, of course, we often have to 'guess' at the elasticities concerned, as reliable information on elasticities, is usually not available.

** Many state utilities have conducted marginal cost pricing studies for their respective jurisdictions. Some of these studies are reviewed by A.Bhattacharyya, (1984). A general review of the tariffs, with their attendant financial implications, may be found in the "Report of the Committee on Power", (1980).

Rs.200 crores (Rs.2000 million) for all the utilities taken together. The average gross return is less than 8% in almost all cases, and if the interest on capital is taken into account, the net return is almost nil. Different official committees have suggested minimum rates of return on capital employed. An Expert Committee headed by Mr. R. Venkataraman suggested in 1964, that the rate of return should be 9% including depreciation and interest; the more recent 'Committee on Power', suggested a rate of return on capital employed (including interest) of 15%.

An examination of the tariffs in the present day utilities shows that they are much below long-run marginal costs in most categories*. In some cases, such as for agricultural pumpsets/tubewells, the effective tariffs are far below long-run marginal costs. In the electric utility industry in India, LRMC is higher than average costs of power supply, in respect of most consumer categories. Electricity tariffs are below even average costs of supply in some of the major categories, such as agricultural pumpsets.

It has been earlier argued that an ideal tariff would be based on the long-term marginal (incremental) costs of supplying electricity to any consumer. This would depend on the voltage level, the distribution system which serves the consumer in question, and the time pattern of the consumer's demand in relation to the system peak/potential peak periods. The need to distinguish consumers into categories, stems basically from the necessity of avoiding complexity in the tariffs. Complexity imposes its own costs (of administration, collection, metering, etc.) which must be set against the benefits likely from such a complicated tariff which seeks to reflect costs in respect of each consumer. Owing to these considerations, consumers are grouped into categories mainly on the basis of similarity in load characteristics.

The question that arises is whether it is possible to implement a marginal cost-based tariff in the case of the Indian utilities, and if so, what should be the approach adopted? There are two methods of reflecting marginal costs in tariffs for any consumer category. The first method is to estimate the level and time

---

* For some figures in this respect, see A.Bhattacharya (1984).

pattern of demand, and the contribution of the consumer-category concerned, to the system peak period, and then arrive at a time-uniform tariff that reflects the marginal costs of meeting this requirement. The second method is to evolve a tariff, i.e. time-differentiated and reflects the costs of supplying these requirement during different period of the 24 hour cycle. The first method is generally used for the smaller consumer categories, in whose case the costs of metering etc. of time-differentiated tariffs, may well outweigh the likely benefits. In the following paragraphs, a broad indication is given of the approach that can be adopted.

(i) Domestic Consumers: There is no rational economic justification for separate rates for domestic lights/fans and domestic small power. The costs of supplying power to the two categories are the same, except for a peaking element in the case of lighting loads alone. Formerly, such a distinction was made in some state utilities to stimulate the use of electric gadgets, such as refrigerators, etc., but the differential rate has been given up by many utilities. It should be eliminated altogether, especially as electricity is now in short supply and there is no need to stimulate consumption by the relatively richer classes, who will be using electric gadgets. For similar reasons, there should be no distinction between commercial light/fan and commercial small power.

(ii) There are declining blocks in certain categories in some of the state utilities. As costs do not significantly decline in this range, and since there is an overall shortage of power, there is no question of helping capacity utilization by additional consumption in any category. It is needless to add that declining blocks should not be used to stimulate consumption when the need is to conserve power.

(iii) Similarly, in the case of industries taking power supply at high voltage (11 KV and above) there is scope for considerable simplification and reduction in the number of categories to two or three, with rates, of course, for different voltages based on the costs of supply. There is scope for introducing peak load tariffs at least in the case of large industrial consumers. In France, the pioneer of marginal cost-based pricing, time-differentiated tariffs were first introduced mainly in the case of large high voltage industrial consumers. Similarly, in many Indian systems, it will be seen that a comparatively small number (in some utilities, this number is less than 100 and in most, it is not more than 200) of high voltage

industrial consumers, are responsible for a significant proportion of total energy consumed. These consumers also are likely to be more responsive to changes in electricity prices, and the costs of time-differentiated metering systems, are also likely to be outweighed by the benefits of this system. Obviously, the introduction of such a system has to be preceded by a period of preparation, as in the Korean example given earlier.*

(iv) Agricultural pumpsets/tubewells:

The tariff in respect of this category, in most state utilities in India, has been the subject of considerable discussion in many forums, and hence it is proposed to discuss it in some detail. The important feature of this category of consumption is that it has been increasing rapidly during the last 15 years, especially after the introduction of high-yielding varieties of wheat in the late 60's, which made assured irrigation both necessary and beneficial to the farmer. The number of pumpsets/tubewells in the country has now crossed the 5 million mark, and in states such as U.P., Haryana and Punjab, more than 30% of the annual energy consumption falls in this category. This category of consumption also has a very significant seasonal aspect; apart from this, the load is scattered, and the annual level of utilization is comparatively low, generally around 1000 hours during the year with exceptions such as Punjab, Haryana and U.P., which utilise these pumpsets for around 1500 hours. The Committee on Power has shown how the tariff for this category is substantially below even the average costs of supply in all the utilities.** In fact, this category is substantially responsible for the losses of many State Electricity Boards.

Apart from the overall tariff being substantially below the average (and, therefore, much below marginal) costs, another important feature of the pumpset tariff deserves mention here. In many state utilities, e.g. Punjab, Haryana, U.P., Karnataka and Andhra Pradesh, the agricultural tariff is framed in the form of a "flat rate" tariff, i.e. the tariff is charged per horse power of the pumpset, irrespective of the number of hours used. This is against basic economic principles, as the marginal cost of usage of the pumpset is zero in such a case.

---

* Some state utilities, e.g. Gujarat have introduced off peak concessions, but the effects of this limited form of peakload pricing, are yet to be seen.

** See Report of the Committee on Power, (1980).

It may be pointed out that cross-subsidisation in respect of private tubewells and pumpsets, is generally supported by its proponents on two considerations: (i) The income distribution argument, and (ii) the need to encourage this category of consumption. As far as the income distribution argument is concerned, it is established that the owners of private tubewells/pumpsets, are among the better-off farmers in the rural India.*

Dhawan has made an interesting point about the possible effects of tubewell technology on the efficiency of the traditional means of irrigation, used by small farmers in the vicinity of the larger farmers owning private tubewells and pumpsets. Dhawan points out that there can be a serious problem of lowering of the water table, in the vicinity of tubewells and pumpsets, thus imposing external dis-economies on the resources of traditional wells.** The income distribution argument, therefore, does not support the subsidy being given to private tubewells/pumpsets. It is also doubtful whether the "stimulation of consumption", argument would support a subsidy. There is reason to believe that demand for irrigation water will be inelastic over a considerable range of the price of electricity.+ There are other reasons also for bringing the tariffs for agricultural pumpsets more in accordance with the long-run marginal costs. A recent study has shown that, though electricity-driven pumps are economical from the private point of view, they do not compare very favourably with some other alternatives such as diesel-cum-biogas or even diesel-run pumps, if <u>social</u> costs are considered.#

---

* See Report of the Committee on Power, (1980).

** Dhawan, B.D., (1975).

\+ The elasticity of electricity demand can be as low as 0.24 as shown in a study by Dhawan, B.D., (1973).

\# See Ramesh Bhatia and Armand Pereira, (1984).

13. TOWARDS A RATIONAL ELECTRICITY PRICING POLICY

The objective in a developing country such as India, is obviously to utilise the national resources as economically as possible to achieve the stated economic goals of improving productivity and increasing national income, subject to considerations of equity. Apart from economic considerations, it is obviously not possible for the electricity sector to continue to sustain financial losses in the manner it has been doing so far. If a state electric utility suffers financial losses, obviously the losses have to be met from the state's budgetary resources, which would either come from additional taxation, or from some other public expenditure, which is given up at the margin. The social and economic consequences of such an income transfer from non-electricity users to electricity users, are difficult to quantify, but are nevertheless real.

In conclusion, we can perhaps make the following specific suggestions, in regard to electricity pricing in Indian utilities:

(i) Tariffs should move, gradually, closer to long-run marginal costs.

(ii) As the present tariffs are far below long-run marginal costs in respect of many consumer categories, the immediate objective should be to cover atleast average costs in each category, (to the extent they can be estimated) i.e. there should be no revenue losses.

(iii) Subsidies, if at all necessary, should be confined to essential, socially justifiable and specific categories such as street-lighting, domestic electricity supply in remote rural areas, small and marginal farmers, etc.

(iv) There should, in any case, be no subsidy for energising (profitable) economic activity, viz., irrigation, industry etc.

REFERENCES

1. BAUMOL and BRADFORD, American Economic Review, Vol.60, June 1970.

2. BHATTACHARYYA A., (1984) "Marginal Cost-based Tariffs in Indian Power Sector - A Critical Review", Discussion Paper, Tata Energy Research Institute, New Delhi.

3. BHATIA, RAMESH and ARMAND PEREIRA (Ed.), (1984), "Socio-Economic Evaluation of Renewable Energy Technologies", International Labour Organisation, Geneva, Chapter V.

4. BOITEAUX, R. in Nelson J.R. (Ed.) "Marginal Cost Pricing in Practice", Prentice Hall (1964a).

5. BOITEAUX, R., "Peak Load Pricing", in Nelson (Ed.), Marginal Cost Pricing in Practice, Prentice Hall (1964b).

6. BOITEAUX, R. and STASI, P., "Determination of Costs of Expansion in an Interconnected System of Production and Distribution of Electricity, in Nelson J.R. (ED.), (1964) Marginal Cost Pricing in Practice, Prentice Hall, Chapter 5.

7. BONBRIGHT, JAMES C., (1964), "Principles of Public Utility Rates", cited in Carfield & Lovejoy, Public Utility Economics, New York.

8. DHAWAN B.D., (1973), "Demand for Irrigation", Indian Journal of Agricultural Economics, April/June 1973.

9. DHAWAN, B.D., "Review of Agriculture", Economic and Political Weekly, June 21/28, 1975.

10. FARRELL, M.J., (1958), "In Defence of Public-Utility Price Theory", Oxford Economic Papers, New Series Vol.10, reprinted in Turvey (Ed.) Public Enterprise, Penguin Books, 1968.

11. GOVERNMENT OF INDIA, (1980), "Report of the Committee on Power",New Delhi, Chapter 5.

12. HOTELLING, H., (1938), "The General Welfare in relation to Problems of Taxation and of Railway and Utility Rates", Econometrica, Vol.6.

13. KAHN, A.E., (1970a), "The Economics of Regulation", Wiley, New York, Vol.I, p.140.

14. KAHN, A.E., (1970b), "The Economics of Regulation", Wiley, New York, Vol.I, pp 100-103.

15. MASSE', PIERRE' in NELSON J.R. (Ed.) (1964), "Marginal Cost Pricing in Practice", Prentice Hall.

16. MEEK R.L., (1973), "Application of Marginal Cost Pricing - the Green Tariff in Theory and Practice", Journal of Industrial Economics, July, November.

17. MUNASINGHE and WARFORD, (1982), "Electricity Pricing, Theory and Case Studies", Johns Hopkins University Press, Baltimore.

18. MUNASINGHE and RUNGTA, (1984), "Power Tariffs - An Overview", in Cost and Pricing Electricity in Developing Countries, Asian Development Bank.

19. ROUX J.Pl., "Marginal Cost Pricing: Updating the French Electricity Tariffs", in Costing and Pricing Electricity in Developing Countries, Munasinghe and Rungta (Ed.), Asian Development Bank (1984).

20. RUGGLES, NANCY, (1968), "Recent Developments in the theory of Marginal Cost Pricing", reprinted in Turvey (Ed.), Public Enterprises, Penguin Books, London.

21. STIGLER, GEORGE J., "The Theory of Price", Macmillan, New York, p.223.

22. Bell Journal of Economics, "Symposium on Peak Load Pricing", Spring 76, Vol.7,No.1.

23. TURVEY, R., (1968), "Optimal Pricing and Electricity Supply", The MIT Press, Cambridge.

24. TURVEY, R. & ANDERSON D., (1977), "Electricity Economics", Johns Hopkins University Press, Chap.2.

25. YOON HI WOO, "Korea: Peak Load Pricing based on LRMC", in 'Costing and Pricing Electricity in Developing Countries, Munasinghe and Rungta (Ed.), Asian Development Bank, p.295-307, 1984.